

VISIT...

LANZAROTE
Caliente.COM

3

Transmission Line Protection

3.1	The Nature of Relaying.....	3-2
	Reliability • Zones of Protection • Relay Speed • Primary and Backup Protection • Reclosing • System Configuration	
3.2	Current Actuated Relays	3-5
	Fuses • Inverse-Time Delay Overcurrent Relays • Instantaneous Overcurrent Relays • Directional Overcurrent Relays	
3.3	Distance Relays	3-8
	Impedance Relay • Admittance Relay • Reactance Relay	
3.4	Pilot Protection	3-10
	Directional Comparison • Transfer Tripping • Phase Comparison • Pilot Wire	
3.5	Relay Designs	3-11
	Electromechanical Relays • Solid-State Relays • Computer Relays	

Stanley H. Horowitz
Consultant

The study of transmission line protection presents many fundamental relaying considerations that apply, in one degree or another, to the protection of other types of power system protection. Each electrical element, of course, will have problems unique to itself, but the concepts of reliability, selectivity, local and remote backup, zones of protection, coordination and speed which may be present in the protection of one or more other electrical apparatus are all present in the considerations surrounding transmission line protection.

Since transmission lines are also the links to adjacent lines or connected equipment, transmission line protection must be compatible with the protection of all of these other elements. This requires coordination of settings, operating times and characteristics.

The purpose of power system protection is to detect faults or abnormal operating conditions and to initiate corrective action. Relays must be able to evaluate a wide variety of parameters to establish that corrective action is required. Obviously, a relay cannot prevent the fault. Its primary purpose is to detect the fault and take the necessary action to minimize the damage to the equipment or to the system. The most common parameters which reflect the presence of a fault are the voltages and currents at the terminals of the protected apparatus or at the appropriate zone boundaries. The fundamental problem in power system protection is to define the quantities that can differentiate between normal and abnormal conditions. This problem is compounded by the fact that “normal” in the present sense means outside the zone of protection. This aspect, which is of the greatest significance in designing a secure relaying system, dominates the design of all protection systems.

3.1 The Nature of Relaying

3.1.1 Reliability

Reliability, in system protection parlance, has special definitions which differ from the usual planning or operating usage. A relay can misoperate in two ways: it can fail to operate when it is required to do so, or it can operate when it is not required or desirable for it to do so. To cover both situations, there are two components in defining reliability:

Dependability—which refers to the certainty that a relay will respond correctly for all faults for which it is designed and applied to operate; and

Security—which is the measure that a relay will not operate incorrectly for any fault.

Most relays and relay schemes are designed to be dependable since the system itself is robust enough to withstand an incorrect tripout (loss of security), whereas a failure to trip (loss of dependability) may be catastrophic in terms of system performance.

3.1.2 Zones of Protection

The property of security is defined in terms of regions of a power system—called zones of protection—for which a given relay or protective system is responsible. The relay will be considered secure if it responds only to faults within its zone of protection. Figure 3.1 shows typical zones of protection with transmission lines, buses, and transformers, each residing in its own zone. Also shown are “closed zones” in which all power apparatus entering the zone is monitored, and “open” zones, the limit of which varies with the fault current. Closed zones are also known as “differential,” “unit,” or “absolutely selective,” and open zones are “non-unit,” “unrestricted,” or “relatively selective.”

The zone of protection is bounded by the current transformers (CT) which provide the input to the relays. While a CT provides the ability to detect a fault within its zone, the circuit breaker (CB) provides the ability to isolate the fault by disconnecting all of the power equipment inside its zone. When a CT is part of the CB, it becomes a natural zone boundary. When the CT is not an integral part of the CB, special attention must be paid to the fault detection and fault interruption logic. The CTs still define the zone of protection, but a communication channel must be used to implement the tripping function.

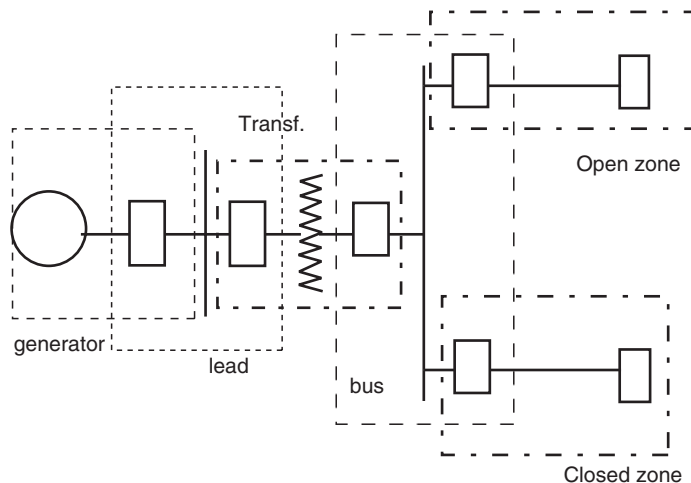


FIGURE 3.1 Closed and open zones of protection. (From Horowitz, S.H. and Phadke, A.G., *Power System Relaying*, 2nd ed., 1995. Research Studies Press, U.K. With permission.)

3.1.3 Relay Speed

It is, of course, desirable to remove a fault from the power system as quickly as possible. However, the relay must make its decision based upon voltage and current waveforms, which are severely distorted due to transient phenomena that follow the occurrence of a fault. The relay must separate the meaningful and significant information contained in these waveforms upon which a secure relaying decision must be based. These considerations demand that the relay take a certain amount of time to arrive at a decision with the necessary degree of certainty. The relationship between the relay response time and its degree of certainty is an inverse one and is one of the most basic properties of all protection systems.

Although the operating time of relays often varies between wide limits, relays are generally classified by their speed of operation as follows:

1. **Instantaneous**—These relays operate as soon as a secure decision is made. No intentional time delay is introduced to slow down the relay response.
2. **Time-delay**—An intentional time delay is inserted between the relay decision time and the initiation of the trip action.
3. **High-speed**—A relay that operates in less than a specified time. The specified time in present practice is 50 milliseconds (3 cycles on a 60 Hz system).
4. **Ultra high-speed**—This term is not included in the Relay Standards but is commonly considered to be operation in 4 milliseconds or less.

3.1.4 Primary and Backup Protection

The main protection system for a given zone of protection is called the primary protection system. It operates in the fastest time possible and removes the least amount of equipment from service. On Extra High Voltage (EHV) systems, i.e., 345kV and above, it is common to use duplicate primary protection systems in case a component in one primary protection chain fails to operate. This duplication is therefore intended to cover the failure of the relays themselves. One may use relays from a different manufacturer, or relays based on a different principle of operation to avoid common-mode failures. The operating time and the tripping logic of both the primary and its duplicate system are the same.

It is not always practical to duplicate every element of the protection chain. On High Voltage (HV) and EHV systems, the costs of transducers and circuit breakers are very expensive and the cost of duplicate equipment may not be justified. On lower voltage systems, even the relays themselves may not be duplicated. In such situations, a backup set of relays will be used. Backup relays are slower than the primary relays and may remove more of the system elements than is necessary to clear the fault.

Remote Backup—These relays are located in a separate location and are completely independent of the relays, transducers, batteries, and circuit breakers that they are backing up. There are no common failures that can affect both sets of relays. However, complex system configurations may significantly affect the ability of a remote relay to “see” all faults for which backup is desired. In addition, remote backup may remove more sources of the system than can be allowed.

Local Backup—These relays do not suffer from the same difficulties as remote backup, but they are installed in the same substation and use some of the same elements as the primary protection. They may then fail to operate for the same reasons as the primary protection.

3.1.5 Reclosing

Automatic reclosing infers no manual intervention but probably requires specific interlocking such as a full or check synchronizing, voltage or switching device checks, or other safety or operating constraints. Automatic reclosing can be high speed or delayed. High Speed Reclosing (HSR) allows only enough time for the arc products of a fault to dissipate, generally 15–40 cycles on a 60 Hz base, whereas time delayed reclosings have a specific coordinating time, usually 1 or more seconds. HSR has the possibility of generator shaft torque damage and should be closely examined before applying it.

It is common practice in the U.S. to trip all three phases for all faults and then reclose the three phases simultaneously. In Europe, however, for single line-to-ground faults, it is not uncommon to trip only the faulted phase and then reclose that phase. This practice has some applications in the U.S., but only in rare situations. When one phase of a three-phase system is opened in response to a single phase-to-ground fault, the voltage and current in the two healthy phases tend to maintain the fault arc after the faulted phase is de-energized. Depending on the length of the line, load current, and operating voltage, compensating reactors may be required to extinguish this “secondary arc.”

3.1.6 System Configuration

Although the fundamentals of transmission line protection apply in almost all system configurations, there are different applications that are more or less dependent upon specific situations.

Operating Voltages—Transmission lines will be those lines operating at 138 kV and above, sub-transmission lines are 34.5 kV to 138 kV, and distribution lines are below 34.5 kV. These are not rigid definitions and are only used to generically identify a transmission system and connote the type of protection usually provided. The higher voltage systems would normally be expected to have more complex, hence more expensive, relay systems. This is so because higher voltages have more expensive equipment associated with them and one would expect that this voltage class is more important to the security of the power system. The higher relay costs, therefore, are more easily justified.

Line Length—The length of a line has a direct effect on the type of protection, the relays applied, and the settings. It is helpful to categorize the line length as “short,” “medium,” or “long” as this helps establish the general relaying applications although the definition of “short,” “medium,” and “long” is not precise. A short line is one in which the ratio of the source to the line impedance (SIR) is large (>4 e.g.), the SIR of a long line is 0.5 or less and a medium line’s SIR is between 4 and 0.5. It must be noted, however, that the per-unit impedance of a line varies more with the nominal voltage of the line than with its physical length or impedance. So a “short” line at one voltage level may be a “medium” or “long” line at another.

Multiterminal Lines—Occasionally, transmission lines may be tapped to provide intermediate connections to additional sources without the expense of a circuit breaker or other switching device. Such a configuration is known as a multiterminal line and, although it is an inexpensive measure for strengthening the power system, it presents special problems for the protection engineer. The difficulty arises from the fact that a relay receives its input from the local transducers, i.e., the current and voltage at the relay location. Referring to Fig. 3.2, the current contribution to a fault from the intermediate source is not monitored. The total fault current is the sum of the local current plus the contribution from the intermediate source, and the voltage at the relay location is the sum of the two voltage drops, one of which is the product of the unmonitored current and the associated line impedance.

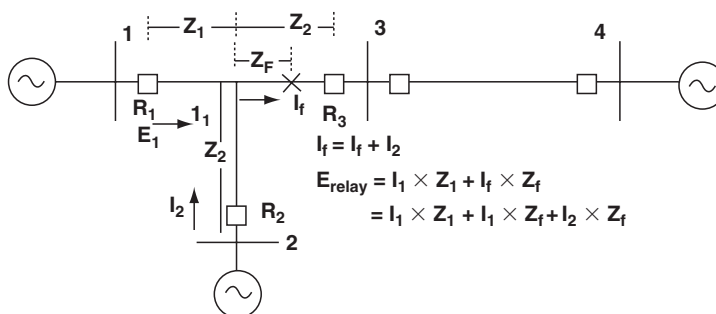


FIGURE 3.2 Effect of infeed on local relays. (From Horowitz, S.H. and Phadke, A.G., *Power System Relaying*, 2nd ed., 1995. Research Studies Press, U.K. With permission.)

3.2 Current Actuated Relays

3.2.1 Fuses

The most commonly used protective device in a distribution circuit is the fuse. Fuse characteristics vary considerably from one manufacturer to another and the specifics must be obtained from their appropriate literature. Figure 3.3 shows the time-current characteristics which consist of the minimum melt and total clearing curves.

Minimum melt is the time between initiation of a current large enough to cause the current responsive element to melt and the instant when arcing occurs. Total Clearing Time (TCT) is the total time elapsing from the beginning of an overcurrent to the final circuit interruption; i.e., $TCT = \text{minimum melt} + \text{arcing time}$.

In addition to the different melting curves, fuses have different load-carrying capabilities. Manufacturer's application tables show three load-current values: continuous, hot-load pickup, and cold-load pickup. Continuous load is the maximum current that is expected for three hours or more for which the fuse will not be damaged. Hot-load is the amount that can be carried continuously, interrupted, and immediately reenergized without melting. Cold-load follows a 30-min outage and is the high current that is the result in the loss of diversity when service is restored. Since the fuse will also cool down during this period, the cold-load pickup and the hot-load pickup may approach similar values.

3.2.2 Inverse-Time Delay Overcurrent Relays

The principal application of time-delay overcurrent relays (TDOC) is on a radial system where they provide both phase and ground protection. A basic complement of relays would be two phase and one ground relay. This arrangement will protect the line for all combinations of phase and ground faults using the minimum number of relays. Adding a third phase relay, however, provides complete backup protection, that is two relays for every type of fault, and is the preferred practice. TDOC relays are usually used in industrial systems and on subtransmission lines that cannot justify more expensive protection such as distance or pilot relays.

There are two settings that must be applied to all TDOC relays: the pickup and the time delay. The pickup setting is selected so that the relay will operate for all short circuits in the line section for which it is to provide protection. This will require margins above the maximum load current, usually twice the expected value, and below the minimum fault current, usually $1/3$ the calculated phase-to-phase or phase-to-ground fault current. If possible, this setting should also provide backup for an adjacent line section or adjoining equipment. The time-delay function is an independent parameter that is obtained in a variety of ways, either the setting of an induction disk lever or an external timer. The purpose of the time-delay is to enable relays to coordinate with each other. Figure 3.4 shows the family of curves of a single TDOC model. The ordinate is time in milliseconds or

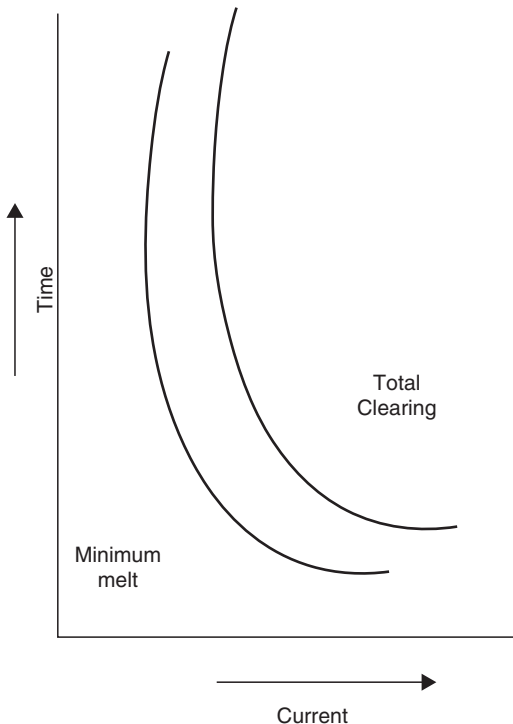


FIGURE 3.3 Fuse time-current characteristic. (From Horowitz, S.H. and Phadke, A.G., *Power System Relaying*, 2nd ed., 1995. Research Studies Press, U.K. With permission.)

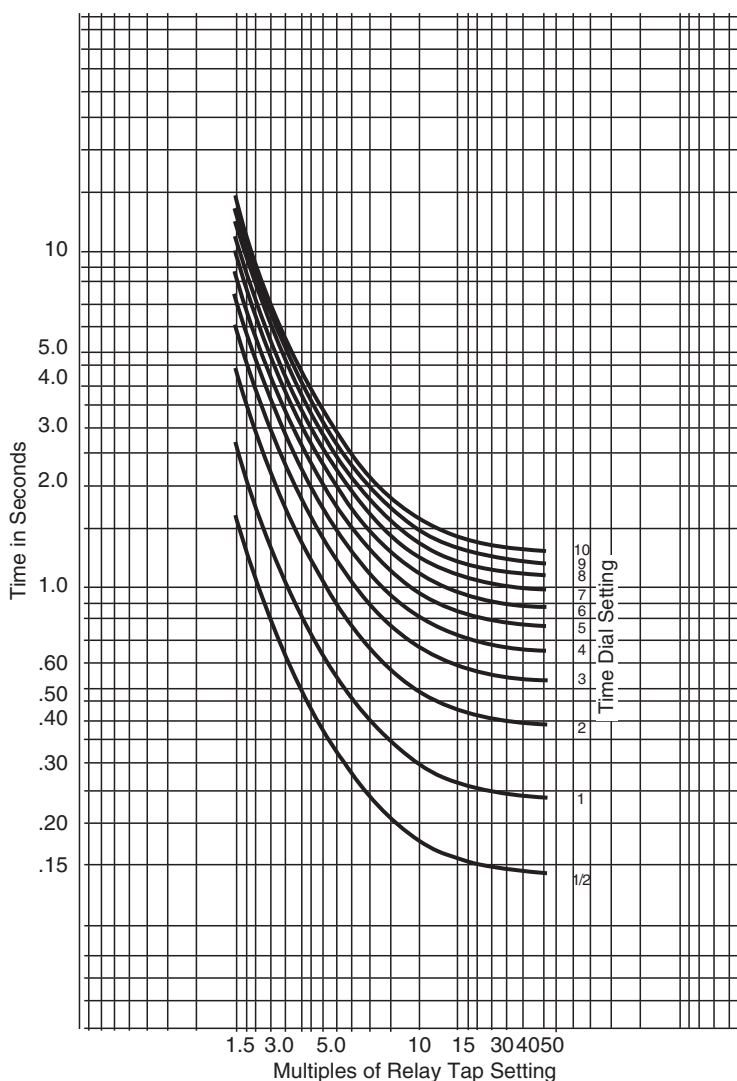


FIGURE 3.4 Family of TDOC time-current characteristics. (From Horowitz, S.H. and Phadke, A.G., *Power System Relaying*, 2nd ed., 1995. Research Studies Press, U.K. With permission.)

seconds depending on the relay type; the abscissa is in multiples of pickup to normalize the curve for all fault current values. [Figure 3.5](#) shows how TDOC relays on a radial line coordinate with each other.

3.2.3 Instantaneous Overcurrent Relays

Figure 3.5 also shows why the TDOC relay cannot be used without additional help. The closer the fault is to the source, the greater the fault current magnitude, yet the longer the tripping time. The addition of an instantaneous overcurrent relay makes this system of protection viable. If an instantaneous relay can be set to “see” almost up to, but not including, the next bus, all of the fault clearing times can be lowered as shown in [Fig. 3.6](#). In order to properly apply the instantaneous overcurrent relay, there must be a substantial reduction in short-circuit current as the fault moves from the relay toward the far end of the line. However, there still must be enough of a difference in the fault current between the near and far end

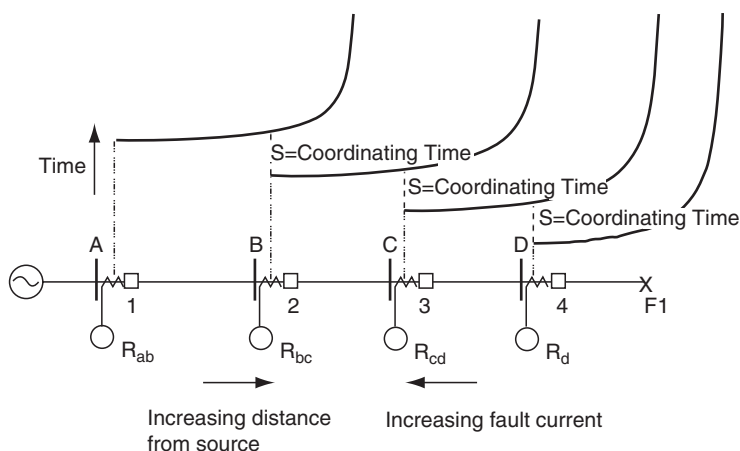


FIGURE 3.5 Coordination of TDOC relays. (From Horowitz, S.H. and Phadke, A.G., *Power System Relaying*, 2nd ed., 1995. Research Studies Press, U.K. With permission.)

faults to allow a setting for the near end faults. This will prevent the relay from operating for faults beyond the end of the line and still provide high-speed protection for an appreciable portion of the line.

Since the instantaneous relay must not see beyond its own line section, the values for which it must be set are very much higher than even emergency loads. It is common to set an instantaneous relay about 125–130% above the maximum value that the relay will see under normal operating situations and about 90% of the minimum value for which the relay should operate.

3.2.4 Directional Overcurrent Relays

Directional overcurrent relaying is necessary for multiple source circuits when it is essential to limit tripping for faults in only one direction. If the same magnitude of fault current could flow in either direction at the relay location, coordination cannot be achieved with the relays in front of, and, for the same fault, the relays behind the nondirectional relay, except in very unusual system configurations.

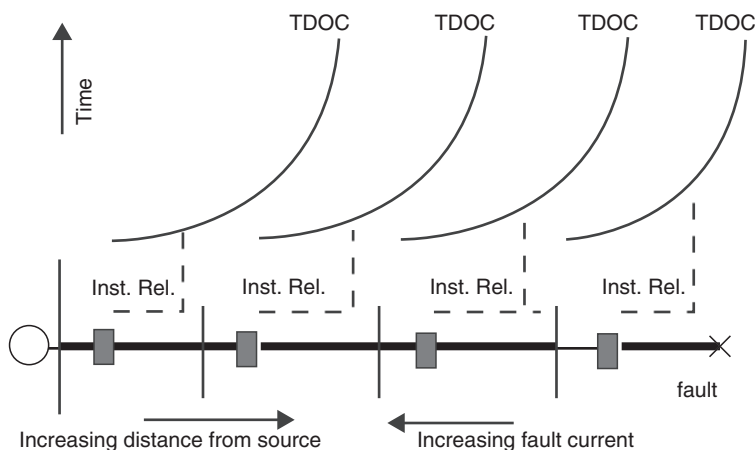


FIGURE 3.6 Effect of instantaneous relays. (From Horowitz, S.H. and Phadke, A.G., *Power System Relaying*, 2nd ed., 1995. Research Studies Press, U.K. With permission.)

Polarizing Quantities—To achieve directionality, relays require two inputs; the operating current and a reference, or polarizing, quantity that does not change with fault location. For phase relays, the polarizing quantity is almost always the system voltage at the relay location. For ground directional indication, the zero-sequence voltage ($3E_0$) can be used. The magnitude of $3E_0$ varies with the fault location and may not be adequate in some instances. An alternative and generally preferred method of obtaining a directional reference is to use the current in the neutral of a wye-grounded/delta power transformer.

3.3 Distance Relays

Distance relays respond to the voltage and current, i.e., the impedance, at the relay location. The impedance per mile is fairly constant so these relays respond to the distance between the relay location and the fault location. As the power systems become more complex and the fault current varies with changes in generation and system configuration, directional overcurrent relays become difficult to apply and to set for all contingencies, whereas the distance relay setting is constant for a wide variety of changes external to the protected line.

There are three general distance relay types as shown in Fig. 3.7. Each is distinguished by its application and its operating characteristic.

3.3.1 Impedance Relay

The impedance relay has a circular characteristic centered at the origin of the R-X diagram. It is nondirectional and is used primarily as a fault detector.

3.3.2 Admittance Relay

The admittance relay is the most commonly used distance relay. It is the tripping relay in pilot schemes and as the backup relay in step distance schemes. Its characteristic passes through the origin of the R-X diagram and is therefore directional. In the electromechanical design it is circular, and in the solid state design, it can be shaped to correspond to the transmission line impedance.

3.3.3 Reactance Relay

The reactance relay is a straight-line characteristic that responds only to the reactance of the protected line. It is nondirectional and is used to supplement the admittance relay as a tripping relay to make the

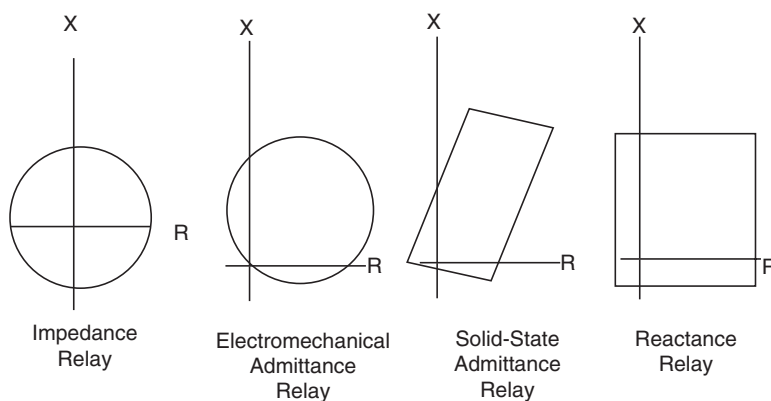


FIGURE 3.7 Distance relay characteristics. (From Horowitz, S.H. and Phadke, A.G., *Power System Relaying*, 2nd ed., 1995. Research Studies Press, U.K. With permission.)

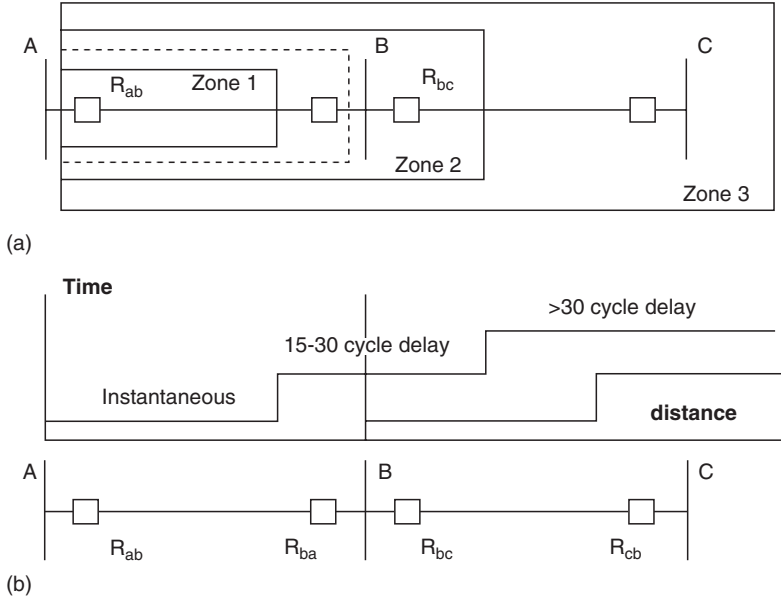


FIGURE 3.8 Three-zone step distance relaying to protect 100% of a line and backup the neighboring line. (From Horowitz, S.H. and Phadke, A.G., *Power System Relaying*, 2nd ed., 1995. Research Studies Press, U.K. With permission.)

overall protection independent of resistance. It is particularly useful on short lines where the fault arc resistance is the same order of magnitude as the line length.

Figure 3.8 shows a three-zone step distance relaying scheme that provides instantaneous protection over 80–90% of the protected line section (Zone 1) and time-delayed protection over the remainder of the line (Zone 2) plus backup protection over the adjacent line section. Zone 3 also provides backup protection for adjacent lines sections.

In a three-phase power system, 10 types of faults are possible: three single phase-to-ground, three phase-to-phase, three double phase-to-ground, and one three-phase fault. It is essential that the relays provided have the same setting regardless of the type of fault. This is possible if the relays are connected to respond to delta voltages and currents. The delta quantities are defined as the difference between any two phase quantities, for example, $E_a - E_b$ is the delta quantity between phases a and b. In general, for a multiphase fault between phases x and y,

$$\frac{E_x - E_y}{I_x - I_y} = Z_1 \quad (3.1)$$

where x and y can be a, b, or c and Z_1 is the positive sequence impedance between the relay location and the fault. For ground distance relays, the faulted phase voltage, and a compensated faulted phase current must be used.

$$\frac{E_x}{I_x + mI_0} = Z_1 \quad (3.2)$$

where m is a constant depending on the line impedances, and I_0 is the zero sequence current in the transmission line. A full complement of relays consists of three phase distance relays and three ground distance relays. This is the preferred protective scheme for high voltage and extra high voltage systems.

3.4 Pilot Protection

As can be seen from Fig. 3.8, step distance protection does not offer instantaneous clearing of faults over 100% of the line segment. In most cases this is unacceptable due to system stability considerations. To cover the 10–20% of the line not covered by Zone 1, the information regarding the location of the fault is transmitted from each terminal to the other terminal(s). A communication channel is used for this transmission. These pilot channels can be over power line carrier, microwave, fiberoptic, or wire pilot. Although the underlying principles are the same regardless of the pilot channel, there are specific design details that are imposed by this choice.

Power line carrier uses the protected line itself as the channel, superimposing a high frequency signal on top of the 60 Hz power frequency. Since the line being protected is also the medium used to actuate the protective devices, a blocking signal is used. This means that a trip will occur at both ends of the line unless a signal is received from the remote end.

Microwave or fiberoptic channels are independent of the transmission line being protected so a tripping signal can be used.

Wire pilot channels are limited by the impedance of the copper wire and are used at lower voltages where the distance between the terminals is not great, usually less than 10 miles.

3.4.1 Directional Comparison

The most common pilot relaying scheme in the U.S. is the directional comparison blocking scheme, using power line carrier. The fundamental principle upon which this scheme is based utilizes the fact that, at a given terminal, the direction of a fault either forward or backward is easily determined by a directional relay. By transmitting this information to the remote end, and by applying appropriate logic, both ends can determine whether a fault is within the protected line or external to it. Since the power line itself is used as the communication medium, a blocking signal is used.

3.4.2 Transfer Tripping

If the communication channel is independent of the power line, a tripping scheme is a viable protection scheme. Using the same directional relay logic to determine the location of a fault, a tripping signal is sent to the remote end. To increase security, there are several variations possible. A direct tripping signal can be sent, or additional underreaching or overreaching directional relays can be used to supervise the tripping function and increase security. An underreaching relay sees less than 100% of the protected line, i.e., Zone 1. An overreaching relay sees beyond the protected line such as Zone 2 or 3.

3.4.3 Phase Comparison

Phase comparison is a differential scheme that compares the phase angle between the currents at the ends of the line. If the currents are essentially in phase, there is no fault in the protected section. If these currents are essentially 180° out of phase, there is a fault within the line section. Any communication link can be used.

3.4.4 Pilot Wire

Pilot wire relaying is a form of differential line protection similar to phase comparison, except that the phase currents are compared over a pair of metallic wires. The pilot channel is often a rented circuit from the local telephone company. However, as the telephone companies are replacing their wired facilities with microwave or fiberoptics, this protection must be closely monitored.

3.5 Relay Designs

3.5.1 Electromechanical Relays

Early relay designs utilized actuating forces that were produced by electromagnetic interaction between currents and fluxes, much as in a motor. These forces were created by a combination of input signals, stored energy in springs, and dash pots. The plunger type relays are usually driven by a single actuating quantity while an induction type relay may be activated by a single or multiple inputs (see Figs. 3.9 and 3.10.). Although existing protection is provided primarily by electromechanical relays that is because the cost and complexity of replacing them may be prohibitive; nevertheless, new construction and major system or station revisions are witnessing the replacing of electromechanical relays with solid-state or digital relays.

3.5.2 Solid-State Relays

The expansion and growing complexity of modern power systems have brought a need for protective relays with a higher level of performance and more sophisticated characteristics. This has been made possible by the development of semiconductors and other associated components, which can be utilized in many designs, generally referred to as solid-state or static relays. All of the functions and characteristics available with electromechanical relays are available with solid-state relays. They use low-power components but have limited capability to tolerate extremes of temperature, humidity, overvoltage, or overcurrent. Their settings are more repeatable and hold to closer tolerances and their characteristics can be shaped by adjusting the logic elements as opposed to the fixed characteristics of electromechanical relays. This can be a distinct advantage in difficult relaying situations. Solid-state relays are designed, assembled, and tested as a system that puts the overall responsibility for proper operation of the relays on the manufacturer. [Figure 3.11](#) shows a solid-state instantaneous overcurrent relay.

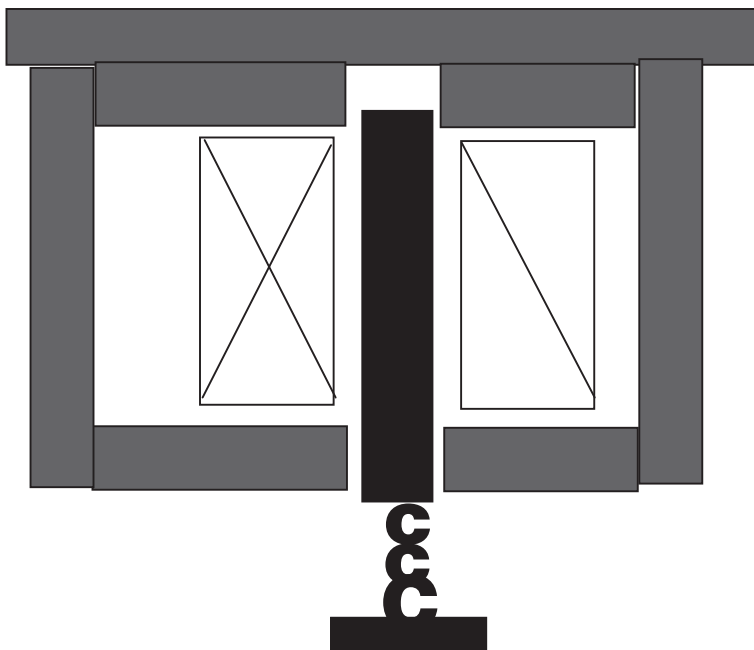


FIGURE 3.9 Plunger type relay.

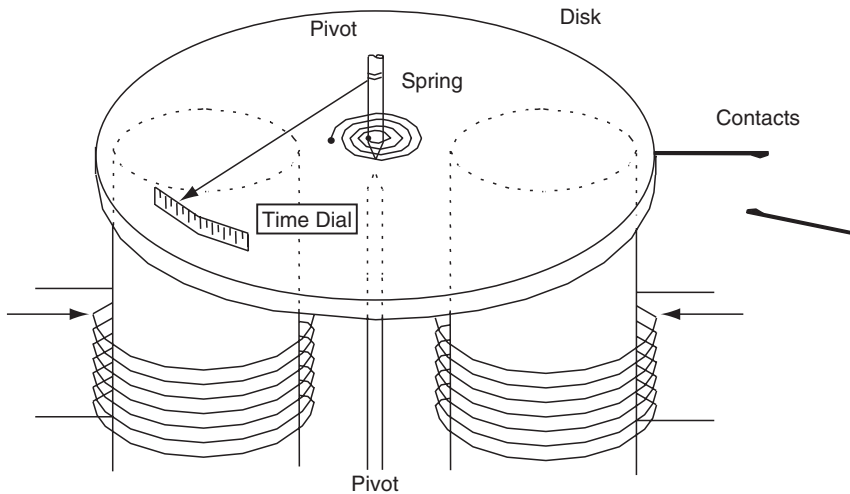


FIGURE 3.10 Principle of construction of an induction disk relay. Shaded poles and damping magnets are omitted for clarity.

3.5.3 Computer Relays

It has been noted that a relay is basically an analog computer. It accepts inputs, processes them electromechanically or electronically to develop a torque or a logic output, and makes a decision resulting in a contact closure or output signal. With the advent of rugged, high-performance microprocessors, it is obvious that a digital computer can perform the same function. Since the usual relay inputs consist of power system voltages and currents, it is necessary to obtain a digital representation of these parameters. This is done by sampling the analog signals, and using an appropriate algorithm to create suitable digital representations of the signals. The functional blocks in Fig. 3.12 represent a possible configuration for a digital relay.

In the early stages of their development, computer relays were designed to replace existing protection functions, such as transmission line and transformer or bus protection. Some relays used microprocessors to make the relay decision from digitized analog signals; others continue to use analog functions to make the relaying decisions and digital techniques for the necessary logic and auxiliary functions. In all cases, however, a major advantage of the digital relay was its ability to diagnose itself; a capability that could only be obtained, if at all, with great effort, cost, and complexity. In addition, the digital relay provides a communication capability to warn system operators when it is not functioning properly, permitting remote diagnostics and possible correction.

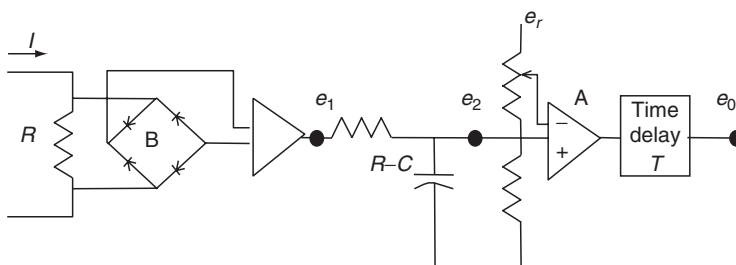


FIGURE 3.11 A possible circuit configuration for a solid-state instantaneous overcurrent delay.

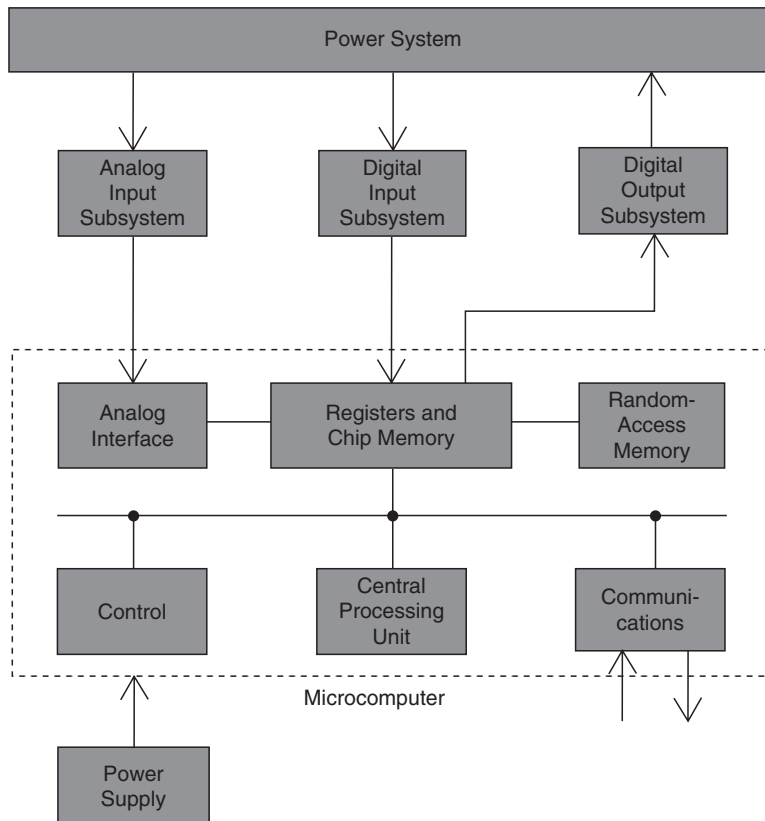


FIGURE 3.12 Major subsystem of a computer relay.

As digital relay investigations continued another dimension was added. The ability to adapt itself, in real time, to changing system conditions is an inherent, and important, feature in the software-dominated relay. This adaptive feature is rapidly becoming a vital aspect of future system reliability.

